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Citation for published version:

Al-zaidi, E, Fan, X & Edlmann, K 2018, 'Supercritical CO₂ behaviour during water displacement in a sandstone core sample', *International Journal of Greenhouse Gas Control*, vol. 79, pp. 200-211.
<https://doi.org/10.1016/j.ijggc.2018.11.005>

Digital Object Identifier (DOI):

[10.1016/j.ijggc.2018.11.005](https://doi.org/10.1016/j.ijggc.2018.11.005)

Link:

[Link to publication record in Edinburgh Research Explorer](#)

Document Version:

Peer reviewed version

Published In:

International Journal of Greenhouse Gas Control

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Supercritical CO₂ Behaviour during Water Displacement in a Sandstone Core Sample

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Abstract: CO₂ injection into underground formations involves the flow of CO₂ in subsurface rocks which already contain water. The flow of CO₂ into the target formation is governed mainly by capillary forces, viscous forces and interfacial interactions. Any change in subsurface conditions of pressure and temperature during injection will have an impact on the capillary and viscous forces and the interfacial interactions, which, in turn, will have an influence the injection, displacement, migration, and storage capacity and security of CO₂. In this study, an experimental investigation has been designed to explore the impact of fluid pressure (74-90 bar), temperature (33-55 °C), and injection rate (0.1-1 ml/min) on the dynamic pressure evolution and displacement efficiency when supercritical CO₂ is injected into a water-saturated sandstone core sample. The study also highlights the impact of the capillary forces and viscous forces on the two-phase flow characteristics and shows the conditions where capillary forces or viscous forces become dominant. The authors are not aware of similar experimental studies conducted in the literature so far. The results revealed a moderate to considerable impact of the parameters investigated on the differential pressure profile, cumulative produced volumes, endpoint CO₂ relative (effective) permeability and residual water saturation. The extent of the impact of each parameter (e.g. fluid pressure) was a function of the associated parameters (e.g. temperature and injection rate). Increasing fluid pressure caused the differential pressure profile of supercritical CO₂-water displacement to transform to the likeness of liquid CO₂-water displacement, while, increasing temperature transforms it to the likeness of gaseous CO₂-water displacement. Increasing fluid pressure caused a considerable reduction in the maximum and quasi-differential pressures, an increase in the endpoint CO₂ relative permeability (K_{CO_2}) and a reduction in the residual water saturation (S_{wr}) and

cumulative produced volumes. Overall, the impact of temperature is opposite to [that](#) of fluid pressure. However, with increasing temperature, the K_{rCO_2} showed a declining trend at high-fluid pressures (90 bar) but an increasing trend at low-fluid pressures (75 bar). Increasing injection rate caused a considerable increase in the maximum and quasi-differential pressures, a rise in the K_{rCO_2} , a reduction in the S_{wr} , and an increase in the cumulative produced volumes. The S_{wr} was in range of 0.34-0.41 while K_{rCO_2} was less than 0.37, depending on the operational conditions. Changing the operational conditions caused a higher impact on K_{rCO_2} than that on S_{wr} . The results indicate that capillary forces dominate the multiphase flow characteristics as fluid pressure and temperature are increased.

1 Introduction

The storage of carbon dioxide in deep saline aquifers, abounded or depleted oil and gas reservoirs ([Delshad et al., 2010](#); [Gozalpour et al., 2005](#); [Kaveh et al., 2012](#)), and unminable coal bed seams ([Kaveh et al., 2012](#); [Plug and Bruining, 2007a](#)) is increasingly viewed as a promising technology to mitigate the increasing emissions of anthropogenic CO₂ into the atmosphere due to fossil fuel burning and other human activities ([Bachu, 2001](#); [Hangx et al., 2013](#); [Kazemifar et al., 2015](#)), enhance hydrocarbon recovery or extract geothermal heat ([Kaveh et al., 2012](#); [Tutolo et al., 2015](#)).

During the injection process, supercritical (Sc) CO₂ will displace formation water in an immiscible drainage displacement process ([Bachu, 2000](#); [Basbug et al., 2005](#)). The multiphase flow properties are controlled by the interplay of many factors including capillary forces, viscous forces, gravity forces ([Roof, 1970](#); [Rostami et al., 2010](#)), interfacial interactions, solubility of CO₂ in formation water, phase densities and viscosities of the injected and present fluids, petrophysical properties of the aquifer, and injection rate and its duration ([Pentland et al., 2011](#)). Due to the small pore sizes of subsurface rocks and sands, the capillary forces at the CO₂-water interface will have a considerable influence on the two-phase flow through a porous medium ([Roof, 1970](#)). The interplay between the capillary forces, viscous forces as well as gravity forces governs the displacement front behaviour, which potentially has an impact on fluids distribution, in turn, will have a potential influence on the macroscopic transport

characteristics such as relative permeability and capillary pressure ([Rostami et al., 2010](#)). Change in fluid pressure, temperature, and injection rate will have a direct impact on most of the aforementioned factors; therefore, changing the operational conditions will have a moderate to significant influence on the injectivity ([Müller, 2011](#)), migration, storage and long-term integrity efficiency of CO₂ processes ([Saraji et al., 2013](#)). The CO₂ injectivity is a key factor in determining the amount, pace, and period of CO₂ injection in a saline aquifer ([Mijic et al., 2014](#)).

Multiphase flow corresponding with CO₂ injection into subsurface formations is a complex process, thus conducting core-scale displacements under a wide range of parameters (e.g. different pressure, temperature and injection rate conditions) will provide us with a deeper understanding of the behaviour of immiscible flow through natural porous media, thereby enabling us to build models that approximate physics more closely ([Aryana and Kovscek, 2012](#)). Despite its importance, the multiphase flow properties of CO₂-water (brine) systems are poorly investigated in comparison to CO₂-oil systems ([Bahralolom et al., 1988](#); [Perrin and Benson, 2010](#)). Our literature review shows a large research effort has been allocated to CO₂ wettability ([Al-Menhali and Krevor, 2014](#); [Bikkina, 2011](#); [Farokhpoor et al., 2013a](#); [Kaveh et al., 2012](#); [Li, 2015](#); [Sakurovs and Lavrencic, 2011](#); [Saraji et al., 2013](#); [Yang et al., 2007](#)) and CO₂ interfacial tension ([Aggelopoulos et al., 2010](#); [Bachu and Bennion, 2008, 2009](#); [Busch and Müller, 2011](#); [Chiquet et al., 2007](#); [Li et al., 2012](#); [Yu et al., 2012](#)). Cinar and Riaz in their literature review pointed out the need to more investigations on multiphase flow characteristics of CO₂-(water) brine-solid systems ([Cinar and Riaz, 2014](#)).

The limited investigations of the multiphase flow characteristics of ScCO₂-(water) brine systems are mainly classified into computational modelling ([Jobard et al., 2013](#); [Ma et al., 2013](#); [Mijic et al., 2014](#); [Xu et al., 2011](#)) and laboratory experiments ([Berg et al., 2013](#); [Levine et al., 2011](#); [Pini et al., 2012](#); [Song et al., 2012](#); [Suekane et al., 2005](#); [Zheng et al., 2017](#)). The laboratory ScCO₂-brine (water) experiments have been conducted on various porous media that include synthetic and natural core samples ([Berg et al., 2013](#); [Edlmann et al., 2013](#); [Levine et al., 2011](#); [Pini et al., 2012](#)), micromodels ([Zheng et al., 2017](#)), and packed bed of glass beads ([Song et al., 2012](#); [Suekane et al., 2005](#)). In these experiments, researchers

investigated the multiphase flow properties by measuring various parameters that include: relative permeability curves ([Berg et al., 2013](#); [Chang et al., 2013](#); [Krevor et al., 2013](#); [Suekane et al., 2005](#); [Suenaga and Nakagawa, 2011](#)), capillary pressure curves ([Herring et al., 2014](#); [Wang et al., 2013](#)), CO₂ residual saturation and distribution ([Alemu et al., 2011](#); [Chang et al., 2013](#); [Herring et al., 2014](#); [Pentland et al., 2011](#); [Saeedi et al., 2011](#); [Suekane et al., 2005](#)), heterogeneity impact ([Ott et al., 2015](#); [Perrin and Benson, 2010](#); [Shi et al., 2011](#); [Wang et al., 2013](#)), flow regimes ([Armstrong et al., 2017](#)), water displacement efficiency ([Cao et al., 2016](#)), and formation dry out ([Ott et al., 2011](#)).

Nevertheless, despite the wide research on CO₂-water (brine) systems and despite its high importance, the literature provided shows that the analysis of the pressure data in core flooding has been widely overlooked ([Rezaei and Firoozabadi, 2014](#)). In this paper, laboratory dynamic drainage experiments were performed by injecting pure CO₂ in its supercritical state into the core sample to investigate the impact of fluid pressure, temperature and injection rate on the multiphase flow characteristics, especially focusing on the differential pressure profile, water production profile, residual water saturation, and endpoint effective and relative permeabilities of CO₂. One of the main objectives of this investigation is to shed more light on the impact of capillary forces and viscous forces on the two-phase flow characteristics and highlights the conditions at which the capillary forces or viscous forces become dominant. To the authors' best knowledge, no such experimental investigation has been conducted to explore the dynamic pressure evolution and displacement efficiency when supercritical CO₂ is flooded into a deionised water-saturated sandstone core sample. The results of this study would be of importance for evaluating CO₂ injectivity, fluid migration and entrapment, displacement efficiency, CO₂ storage capacity ([Levine et al., 2011](#); [Wang et al., 2015](#)), and efficiency and integrity of the CO₂ sequestration processes ([Busch and Müller, 2011](#); [Rathnaweera et al., 2015](#)).

2 Materials

The unsteady state dynamic drainage experiments (ScCO₂-water displacements) were conducted on a sandstone core sample from Guillemot A Field in the North Sea. The core sample used in this work is of 2.54 cm diameter and 7.62 cm length. The average porosity and absolute water permeability of the core sample are about 14% and 15.8 millidarcys, respectively. To calculate the core sample pore volume and porosity, the core was saturated with deionized water and then the weight difference between the dry and the wet core sample was used. This study is one in a series, therefore, the core sample description, core sample setup and CO₂-water displacements procedures can be found in Al-Zaidi et al. ([Al-Zaidi et al., 2018b](#)).

3 Results and Discussions

To gain a proper understanding of the two-phase flow characteristics of ScCO₂-water drainage displacements, the differential pressure profile, production profile, residual water saturation and endpoint relative and effective permeabilities of CO₂ were measured and analysed.

The differential pressure refers to the difference between the readings of the pressure transducers at the inlet and the outlet sides of the core sample. The capillary and viscous forces are the most influential forces that govern the differential pressure profile when CO₂ is injected in a horizontal direction. Espinoza and Santamarina related the capillary and viscous forces with the differential pressure ([Espinoza and Santamarina, 2010](#)) as follows:

$$\Delta P = P_{CO_2} - P_{water} = 4 \frac{\sigma_{CO_2-water} \cos \theta}{d} + v \frac{32 L}{d^2} \left(\frac{l_{CO_2} \mu_{CO_2} + l_{water} \mu_{water}}{L} \right) \quad (1)$$

where ΔP is the differential pressure across the core sample (Pa). P_{CO_2} and P_{water} are the CO₂ phase and water bulk pressures, respectively; $\sigma_{CO_2-water}$ is the CO₂-water interfacial tension (mN/m), θ the contact angle between fluids and core sample surface, d (m) the diameter of the largest effective pore ([Chiquet et al., 2007](#); [Farokhpour et al., 2013b](#)), v (m/sec) the fluid velocity in the pores, L (m) the length of the core sample, l (m) length of CO₂ or water phase inside the core sample, and μ (Pa·s) the viscosity

of the fluids. The first term of Eq.1 refers to the Young-Laplace equation, which accounts for the capillary forces, while the second term refers to the Poiseuille's equation ([Espinoza and Santamarina, 2010](#); [Li, 2015](#)), which accounts for the viscous forces. The capillary forces which exist because of the presence of the CO₂-water interface inside pore network ([Bikkina et al., 2016](#)) govern the multiphase flow during immiscible displacements ([Schembre and Kovscek, 2003](#)) and leads to the trapping of one phase by another during immiscible displacements ([Akbarabadi and Piri, 2013](#); [Chatzis and Morrow, 1984](#)). The capillary forces are determined by CO₂-water interfacial tension, wettability of the system as well as the core sample pore size distribution ([Alkan et al., 2010](#); [Bikkina et al., 2016](#); [Chatzis and Morrow, 1984](#); [Fulcher Jr et al., 1985](#)). The viscous forces are governed by the injection rate, the viscosity of the displacing and displaced fluids, and the core sample properties such as cross sectional area, core sample length, and permeability.

In this study, the experimental data has been categorized into four main sections. The first three sections deal with the impact of fluid pressure (75-90 bar), temperature (33-55 °C) and injection rate (0.1- 1ml/min) on the differential pressure profile and production behaviour; while the fourth section deal with their influence on the endpoint CO₂ effective (relative) permeability and residual water saturation. It should be noted that during this study, the corresponding time refers to the time required to reach the maximum-differential pressure at the start of the experiment. The quasi-differential pressure refers to the differential pressure measured at the end of the core flooding. For the pump injection rates of 0.1, 0.4, 0.6, and 1 ml/min, the Darcy flux is around 0.0197, 0.079, 0.118, and 0.197 cm/min while the average linear velocity is around 0.141, 0.564, 0.846, and 1.41 cm/min. It is worth stating that for comparative purposes, we will maintain the use of injection rate from the pump as our reference "flowrate" in this study.

3.1 Effect of Fluid Pressure on the Differential Pressure Profile of ScCO₂-Water Displacements.

To have a thorough understanding about the effect of fluid pressure on the differential pressure and water recovery of ScCO₂-water displacements, experiments were conducted under various fluid

pressures (75-90 bar), temperatures (33 and 45 °C) and injection rates (0.1,0.4, and 1 ml/min). The discussion of the pressure data will be presented in two sections. The first section deals with experiments conducted at 33 °C while the second one deals with experiments performed at 45 °C.

3.1.1 Effect of Fluid Pressure on the Differential Pressure Profile of ScCO₂-Water Displacements Conducted at 33 °C.

The results from Figure 1-3 show that for all fluid pressures, the differential pressure increased sharply; then, it dropped steeply (under low pressure and high temperature conditions) or gradually (under high pressure and low temperature conditions) until it reached a nearly quasi-steady drop. Increasing fluid pressure caused a substantial drop in the maximum and quasi-differential pressures; the extent of this drop decreased as CO₂ injection rate increased. The reduction in the maximum differential pressure was always greater than the reduction in the quasi-differential pressure. The increase or a decrease in the corresponding time with increasing fluid pressure is dependent on the injection rate. Increasing fluid pressure led the differential pressure profile of the ScCO₂-water displacements to transform from the likeness of a gaseous CO₂ behaviour to a liquid-like CO₂ behaviour. It caused also a slight increase in the differential pressure profile of the 90 bar-experiment until it became slightly higher than the differential pressure profile of the 80 bar-experiment at the end of the displacements.

The data from Figure 1-3 present the effect of increasing fluid pressure on the differential pressure profile. The data shows that the profile of the differential pressure is characterized by a sharp increase that is followed by a strong or gradual reduction (depending on the pressure and temperature range) until it reached an almost quasi-steady profile. In general, a similar behaviour has been reported by Bikini et al. and Ott et al. (Bikkina et al., 2016; Ott et al., 2015). The sharp increase in the differential pressure occurred because the injected CO₂ entered the pore network of the sandstone core sample for the first time and had to overcome the entry pressure of the sandstone pore network. According to Eq.1, the strong reduction in the differential pressure can be attributed to the reduction in both capillary and viscous forces. The reduction in the capillary forces is expected to occur when capillary pore throats are

opened to flow, i.e. after CO₂ breakthrough (Kwelle, 2017). On the other hand, the reduction in the viscous forces can be associated with the replacement of a more viscous fluid (water) by a less viscous fluid (CO₂) and with the increase in the CO₂ relative permeability at the expense of water relative permeability (Chang et al., 2013).

The gas expansion effect can occur as a result of the change in the injected CO₂ density due to the temperature difference inside and outside the water bath (Carpenter, 2014; Perrin and Benson, 2010). During this study, the density of the injected CO₂ varies as the CO₂ enters the water bath. The density change, i.e. density ratio, is a function of the injection rate, fluid pressure and the temperature difference from the pump (under room temperature) to the core sample inside the water bath. The density ratio (d_r) suggested by Perrin and Benson (Perrin and Benson, 2010) has been used to calculate the volumetric injection rate inside the core sample. For instance, at a fluid pressure of 40 bar, an injection rate of 1 ml/min at 20 °C becomes 1.108 ml/min at 33 °C.

$$d_r = \frac{d_{CO_2}^{20^\circ C, 40 \text{ bars}}}{d_{CO_2}^{33^\circ C, 40 \text{ bars}}} \quad (3)$$

The data from Figure 1-3 reveal that the increase in the fluid pressure led to a considerable reduction in the maximum and quasi-differential pressures along with the increase or a decrease in the corresponding time depending on the injection rate; the corresponding time increased with increasing fluid pressure at an injection rate of 0.1 ml/min and decreased at an injection rate of 0.4 ml/min and higher. For illustration, the data from Figure 1 exhibits that as the fluid pressure increased (from 75 to 90 bar) at 0.1 ml/min injection rate, the maximum-differential pressure dropped by around 72% (from 0.36 to 0.102 bar) and the quasi-differential pressure decreased by around 69.5% (from 0.154 to 0.047 bar) but the corresponding time increased by around 66% (from 6.5 to 10.8 min). The data from Figure 2 shows that as the fluid pressure increased (from 75 to 90 bar) at 0.4 ml/min, the maximum-differential pressure dropped by around 46.6% (from 1.121 to 0.599 bar), the quasi-differential pressure declined by around 39% (from 0.363 to 0.221 bar), and the corresponding time reduced by around 68.4% (from 1.9 to 0.6 min). The data from Figure 3 shows that increasing the fluid pressure (from 75 to 80 and then

to 90 bar) at 1 ml/min, caused the maximum-differential pressure to drop by around 40% (from 2.492 to 1.496 bar), the quasi-differential pressure to decline by around 38% (from 0.994 to 0.614), and the corresponding time to decline by around 15.6% (from 3.2 to 2.7 min).

The reduction in the differential pressure of supercritical CO₂-water systems is also observed by us with supercritical CO₂-oil systems, for more information see Al-Zaidi et al. (Al-Zaidi et al., 2018a). According to Eq.1, the reduction observed in the differential pressure profile is the net result of the reduction in the capillary forces and the increase in the viscous forces with increasing fluid pressure. The reduction in the capillary forces with increasing fluid pressure is due to the reduction in the CO₂-water interfacial tension, as shown in Figure 4, and the increase in contact angle because of the increase in CO₂ solubility (Jung and Wan, 2012; Plug and Bruining, 2007b; Yang et al., 2007). The increase in the viscous forces with increasing fluid pressure is due to the increase in CO₂ viscosity (Peace software, 2017). For illustration, as the fluid pressure increased from 75 to 90 bar, the ScCO₂ viscosity increased from 33.3095 to 53.837×10^{-6} (Pa·s) (Peace software, 2017), and the CO₂-water interfacial tension (IFT) reduced slightly, by around 3 Nm/m, from around 28 to 25 mN/m as shown in Figure 4 (Bachu and Bennion, 2008). As a result, the reduction observed in the differential pressure with increasing fluid pressure might be related mainly to the increase in contact angle. This is in agreement with the findings by Yang et al. (Yang et al., 2005), Liu et al. (Liu et al., 2010), and Jung and Wan (Jung and Wan, 2012). Yang et al. (Yang et al., 2005) and Liu et al. (Liu et al., 2010) noticed that using a supercritical CO₂ phase with reservoir rocks leads to a higher alteration towards less water-wetting status compared to gaseous and liquid CO₂ phases. Moreover, Jung and Wan (Jung and Wan, 2012) found that contact angle increases significantly with increasing fluid pressure up to 100 bar when the fluid pressure is higher than the critical pressure of CO₂ (larger than 73.8 bar) but remains fairly constant when the fluid pressure is less than the critical pressure or above 100 bar.

Regarding the change in the corresponding time, the increase observed in the corresponding time at low injection rate (0.1 ml/min) can be linked to the transformation of a supercritical CO₂-water behaviour to a liquid-like CO₂-water behaviour; this transformation can result in reducing the mobility

ratio and the expansion impact effect due to the low sensitive nature of liquid CO₂ to pressure and temperature change, more discussion will follow later. However, the reduction in the corresponding time with higher injection rate (0.4 ml/min) is likely to be related to the reduction in the magnitude of the maximum differential pressure with increasing fluid pressure.

The data from Figure 1-2 showed that the drop in the maximum-differential pressure with increasing fluid pressure was always higher than that in the quasi-differential pressure. This can be related to fact that the dynamic reduction in both capillary and viscous forces at the end of the displacement is less than that at the start of the displacement.

The results from Figure 1-2 showed also that as the CO₂ injection rate increased, the reduction in the differential pressure, due to increasing fluid pressure, decreased. This is because the reduction observed in the differential pressure profile is the net result of the increase in the viscous forces and the reduction in the capillary forces with increasing fluid pressure. Thus, with increasing injection rate, the contribution of the viscous forces to the net pressure drop increase while the contribution of the capillary forces decreases (Rezaei and Firoozabadi, 2014), thereby leading to a less reduction in the differential pressure.

The data from Figure 1-2 show also that as the fluid pressure increased, the differential pressure profile of the ScCO₂-water displacements transformed from the likeness of a gaseous CO₂ behaviour to a liquid CO₂ behaviour; this transformation occurs at lower-fluid pressures with increasing injection rate. For instance, the differential pressure profile of the 75 bar-experiment is very similar to that of a typical high-fluid pressure gaseous CO₂-water displacement while that of 90 bar-experiment is virtually identical to that of a typical liquid CO₂-water displacement (Al-Zaidi et al., 2018b). Increasing the CO₂ injection rate from 0.1 to 0.4 ml/min caused the transition from a gaseous to liquid CO₂ behaviour to occur at lower fluid pressure. For the 0.1 ml/min-displacements, the transition towards liquid CO₂ behaviour occurred at 90 bar. Nonetheless, for the 0.4 ml/min-displacements, it started from 77 bar. The similarity to a gaseous or a liquid CO₂ behaviour has been decided mainly on the rate of reduction in

the differential pressure profile during early times of flooding; the gaseous CO₂ displacements are characterized by a high-pressure drop at early stages while the liquid CO₂ displacements are characterized by a slight drop ([Al-Zaidi et al., 2018b](#)). The transformation of the differential pressure profile at low pressures with increasing injection rate can be related to the increase in viscous pressure drop (with increasing injection rate) that leads to a reduction in the total pressure drop (as stated above); this, in turn, caused the appearance of the liquid CO₂ like differential pressure profile, which is characterized by a gradual pressure drop at early stages.

The transformation of the differential pressure profile with increasing fluid pressure proposes that the capillary and viscous properties of a supercritical CO₂ phase become similar to that of gaseous CO₂ phase at low fluid pressures and similar to that of liquid CO₂ phase at high fluid pressures; liquid CO₂ is characterized by higher viscous forces and lesser capillary forces compared to gaseous CO₂. With increasing fluid pressure, the viscous forces of supercritical CO₂ phase become higher while the capillary forces become lesser. This is because the increase in the fluid pressure leads to the increase in the CO₂ viscosity as well as the decrease in the interfacial tension and the increase in the contact angle due to the increasing CO₂ solubility ([Espinoza and Santamarina, 2010](#); [Plug and Bruining, 2007a](#)). Moreover, the transformation towards liquid CO₂ behaviour might have occurred because the wettability behaviour of liquid and supercritical CO₂ phases become very close to each other at high-pressure conditions. The wettability of the core sample with supercritical and liquid CO₂ might have been altered towards hydrophobic wetting status at high pressures. This potential wettability alteration might have occurred due to the fluid pressure increase in case of supercritical CO₂ ([Jung and Wan, 2012](#); [Yang et al., 2005](#)) (as illustrated above), and CO₂ phase transformation in case of liquid CO₂ ([Yang et al., 2007](#)). Yang et al. observed that as gaseous CO₂ phase transforms to liquid CO₂, the wetting status becomes hydrophobic ([Yang et al., 2007](#)).

The data from [Figure 1](#) show that after about 170 min, the differential pressure profile of the 90 bar-experiment experienced a gradual increase until it became slightly higher than the differential

pressure profile of the 80 bar-experiment. The reason is not entirely clear. However, the first possible explanation is that as water depletion progressed and, hence, the viscous pressure drop across the core sample diminished, the flow of CO₂ through non-depleted capillaries was partially blocked by the capillary forces (Nutt, 1982), more discussion can be seen in Al-Zaidi et al. (Al-Zaidi et al., 2018a; Al-Zaidi et al., 2018b). As a result, the pressure of the CO₂ had to build up to a certain level to overcome the capillary forces (Hildenbrand et al., 2002; Nutt, 1982). The second possible explanation is that, after around 170 min, the impact of viscous forces became higher than that of capillary forces as most of the water was displaced; thereby CO₂ was flowing through opened pores. The result was less impact for capillary forces (Kwelle, 2017).

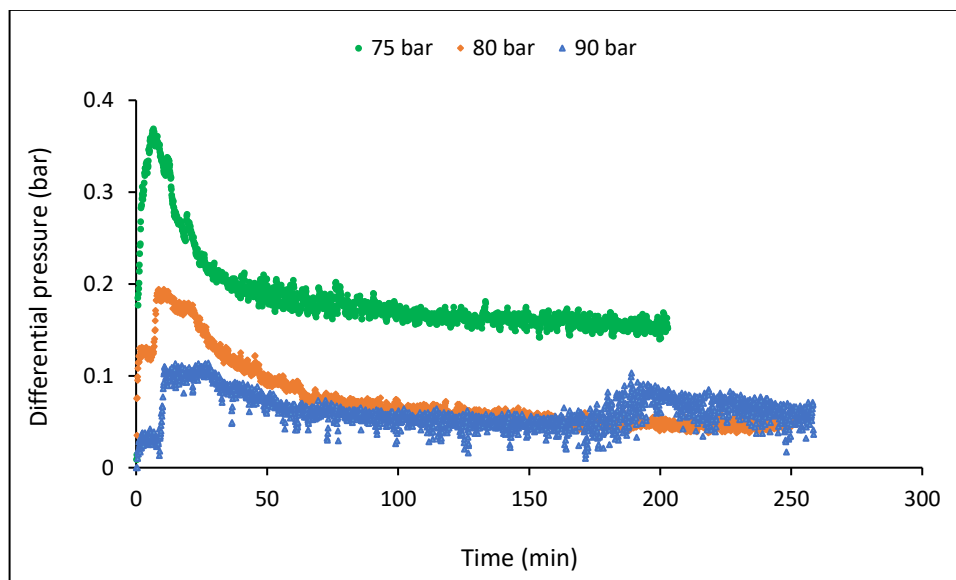


Figure 1: Effect of fluid pressure on the differential pressure profile of ScCO₂-water displacements conducted at 0.1 ml/min and 33 °C.

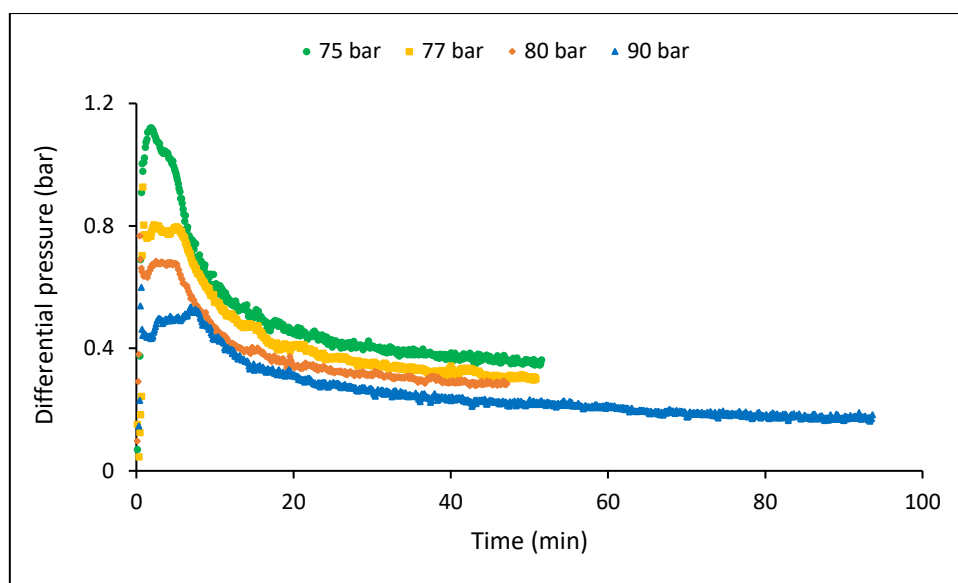


Figure 2: Effect of fluid pressure on the differential pressure profile of ScCO₂-water displacements conducted at 0.4 ml/min and 33 °C.

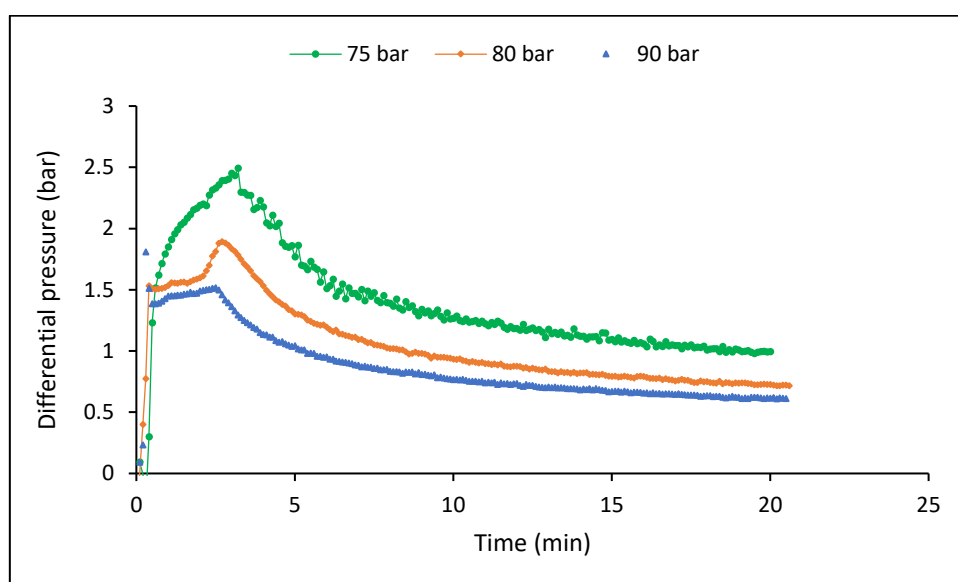


Figure 3: Effect of fluid pressure on the differential pressure profile of ScCO₂-water displacements conducted at 1 ml/min and 33 °C.

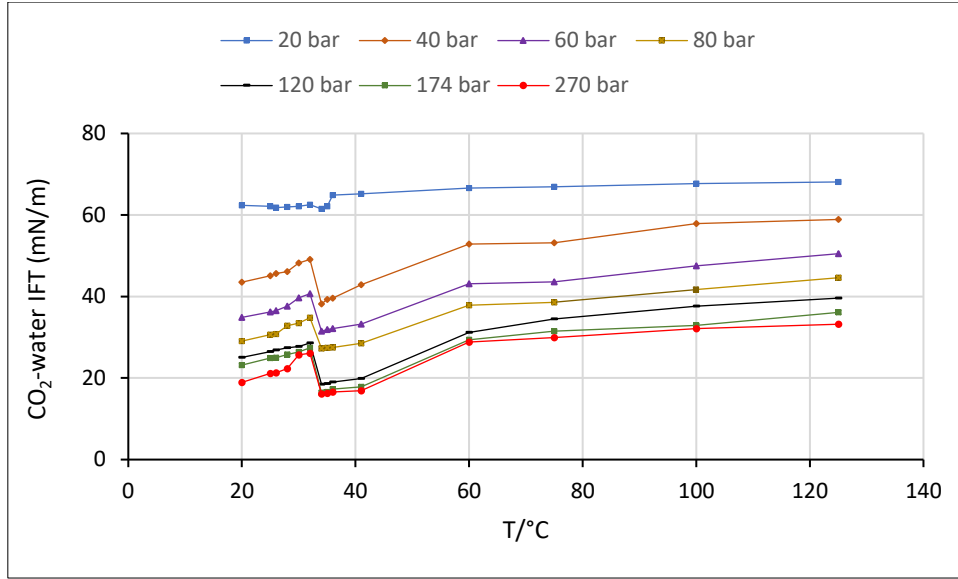


Figure 4: Experimental interfacial tension for CO₂-Pure Water Systems adopted from (Bachu and Bennion, 2008).

3.1.2 Effect of Fluid Pressure on the Differential Pressure Profile of ScCO₂-Water Displacements Conducted at Higher Temperatures (45 °C).

Figure 5 presents the effect of increasing fluid pressure on the differential pressure at a higher temperature (45 °C). Overall, in comparison to experiments conducted under lower temperature (33 °C) conditions, the differential pressure profile of the higher temperature (45 °C) displacements becomes more similar to gaseous CO₂ behaviour than liquid CO₂ behaviour.

The data from Figure 5 reveals also that the differential pressure profile experienced the highest reduction within the first three to five minutes of running the experiments and reached a quasi-pressure state after around 20 min. This indicates that most of the water recovery happened during the first five minutes of running the coreflooding. As a result, the differential pressure profile of the 80 and 90 bar became almost identical after 3.3 min. These nearly identical pressure profiles might have occurred because the reduction in the differential pressure profile (due to the decline of the capillary forces with increasing pressure) was equalled by the increase in the differential pressure profile (owing to the increase of the viscous forces with increasing pressure). This suggests that in comparison to capillary forces, the viscous forces played a vital role at later stages of the displacements. During these stages, it is expected that the bypassed water was concentrated inside the smallest pores and the larger pores

were occupied by the injected CO₂ (Chang et al., 2013). Consequently, the impact of the capillary forces was significantly reduced (Kwelle, 2017).

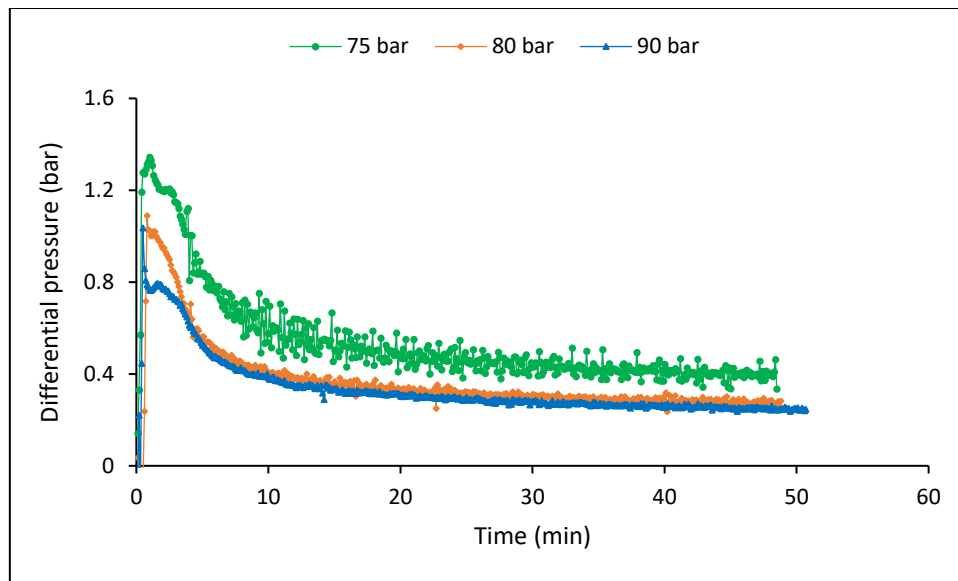


Figure 5: Effect of fluid pressure on the differential pressure profile of ScCO₂-water displacements conducted at 0.4 ml/min, and 45 °C.

3.1.3 Effect of Temperature on the Differential Pressure Profile of ScCO₂-Water Drainage Displacements.

To have a deep understanding of the effect of temperature on the differential pressure and water recovery of ScCO₂-water displacements, a series of experiments were conducted under different temperatures (33 and 45 °C), different injection rates (0.1, 0.4, and 1ml/min), and different fluid pressures (75-90 bar) conditions.

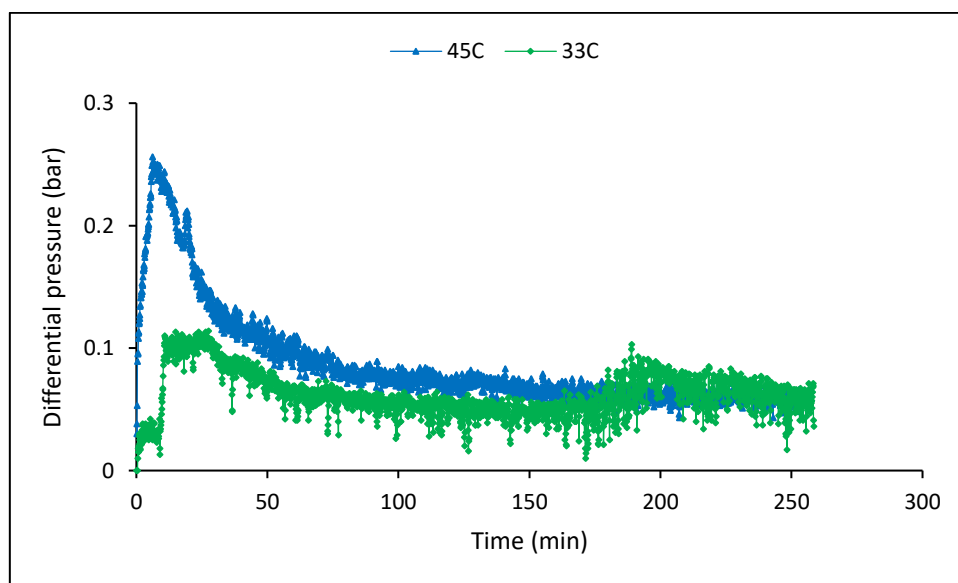
The data from Figure 6-9 show that increasing temperature caused the differential pressure profile to transform to the likeness of gaseous CO₂ behaviour. Increasing temperature caused a significant increase in the maximum and quasi-differential pressures; the extent of this increase increased with the injection rate. The corresponding time decreases or increases depending on the CO₂ injection rate. Increasing temperature at a lower fluid pressure (75 bar) led to the appearance of the differential pressure oscillations in addition to the increase in the maximum and quasi-differential pressures.

The data from Figure 6-9 show the effect of increasing temperature on the differential pressure at different fluid pressures and injection rates. Contrary to the fluid pressure effects, the increase in temperature, from 33 to 45 °C at 90 bar, caused the differential pressure profile to transform to the likeness of gaseous CO₂ behaviour, as shown in Figure 6. The increase in temperature produced a notable increase in the maximum and quasi-differential pressures; the extent of this increase increased with the injection rate. The reduction or increase in the corresponding time is dependent on the CO₂ injection rate; the corresponding time decreased with increasing temperature at an injection rate of 0.1 ml/min and increased with increasing temperature at an injection rate of 0.4 ml/min and higher; which is opposite to the impact of fluid pressure as stated above. For illustration, the data from Figure 6 shows that as the temperature increased (from 33 to 45 °C) at 0.1 ml/min and 90 bar, the maximum-differential pressure increased by around 133% (from around 0.11 to 0.256 bar) but the corresponding times dropped by around 44.5% (from around 11 to 6.1 min). The quasi-differential pressure was almost identical, apart from the gradual increase of the differential pressure profile after about 170 min, see Section 3.1.1 above for more information. The data from Figure 7 shows that increasing the temperature (from 33 to 55 °C) at 0.4 ml/min and 90 bar, caused the maximum-differential pressure to rise by around 75.5% (from 0.599 to 1.051 bar), the quasi-differential pressure to increase by 54% (from 0.224 to 0.345 bar), and the corresponding time to extend by around 17% (from 0.6 to 0.7 ml/min). The corresponding time of both 33 and 45 °C-displacements was equal and their differential profiles were almost identical during the last period. The data from Figure 8 shows that for the displacements conducted at 1 ml/min and 90 bar, increasing the temperature (from 33 to 55 °C) led the maximum-differential pressure to increase by around 246.6% (from 0.786 to 2.724 bar), the quasi-differential pressure to increase by about 201% (from 0.299 to 0.901 bar), and the corresponding time to extend by 47% (from 1.7 to 2.5 min).

According to Eq.1, the increase observed in the differential pressure profile with increasing temperature can be related mainly to the increase in the capillary forces and slightly to the increase in the applied viscous forces. The increase in the capillary forces with increasing temperature is due to the increase in the CO₂-water interfacial tension and the reduction in the contact angle because of the

reduction in CO₂ solubility ([Bachu and Bennion, 2008](#); [Yang et al., 2007](#)). On the other hand, the slight increase in the viscous forces with increasing temperature, despite the reduction in the CO₂ dynamic viscosity, is because of increasing the CO₂ injection rate due to expansion impact. For the experiments conducted at 90 bar-0.4 ml/min, as the temperature increased from 33 to 55 °C, the IFT increased from 25 to 28 mN/m and the CO₂ injection rate inside the core sample increased from 0.506 to 1.296 ml/min but the CO₂ viscosity decreased from 53.837 to 22.26×10^{-6} (Pa·s)]([Peace software, 2017](#)).

The results from [Figure 9](#) show the effect of increasing temperature on the differential pressure at a lower fluid pressure (75 bar). Increasing temperature from 33 to 45 °C led to the appearance of the differential pressure oscillations for the first time. As the temperature further increased to 55 °C, the magnitude of the oscillations increased. Moreover, increasing temperature from 33 to 55 °C caused the maximum-differential pressure to increase by around 29% (from 1.12 to 1.444 bar), the quasi-differential pressure to increase by about 21% (from 0.367 to 0.444 bar) and the corresponding times to prolong by 175% (from 1 to 1.17 min). The differential pressure oscillations are likely to appear because of the reduction in the ratio of the viscous forces to capillary forces. Thus, the capillary forces became higher than the viscous forces and; as a result, the water flow paths were closed ([Nutt, 1982](#)).



[Figure 6](#): Effect of temperature on the differential pressure profile of ScCO₂-water displacements conducted at 90 bar and 0.1 ml/min.

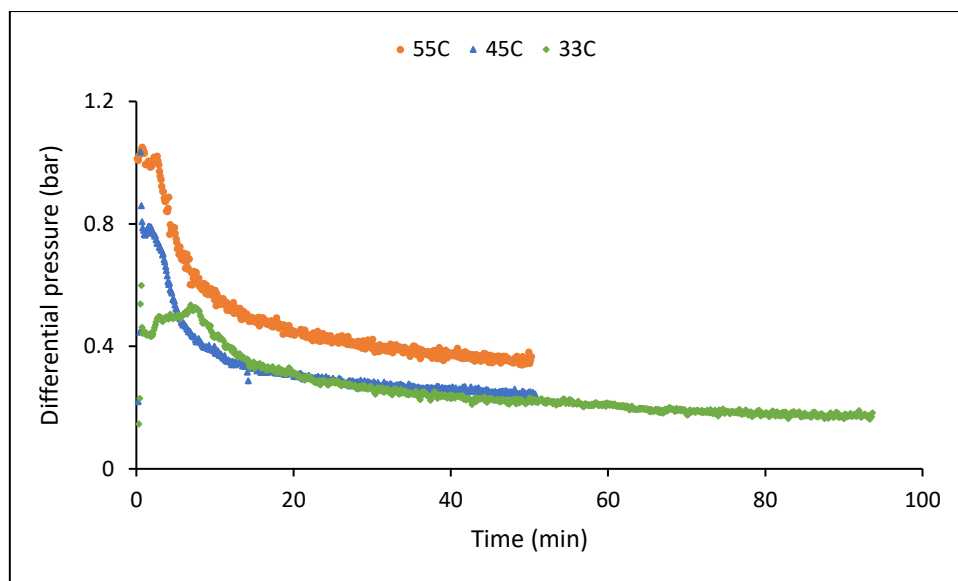


Figure 7: Effect of temperature on the differential pressure profile of ScCO₂-water displacements conducted at 90 bar and 0.4 ml/min.

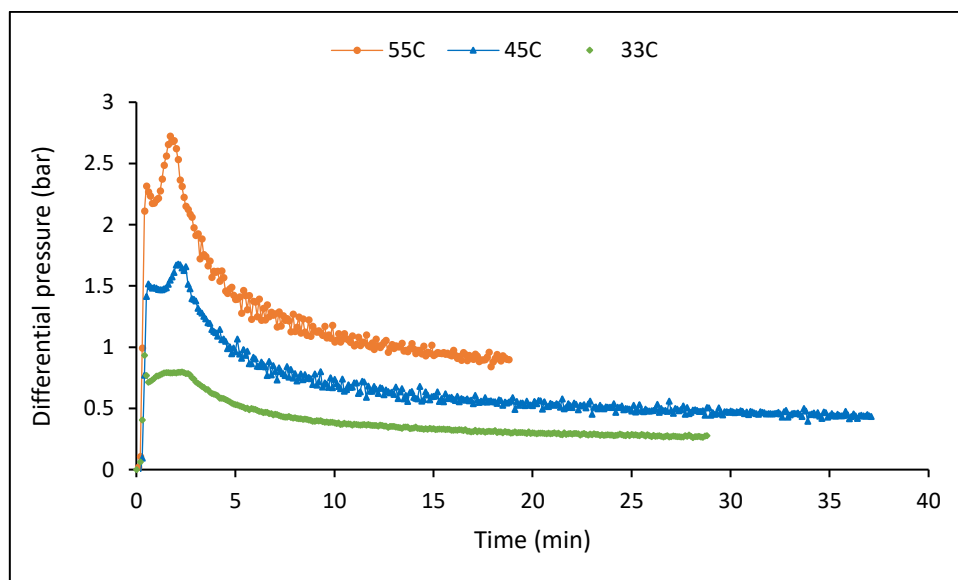


Figure 8: Effect of temperature on the differential pressure profile of ScCO₂-water displacements conducted at 90 bar and 1 ml/min.

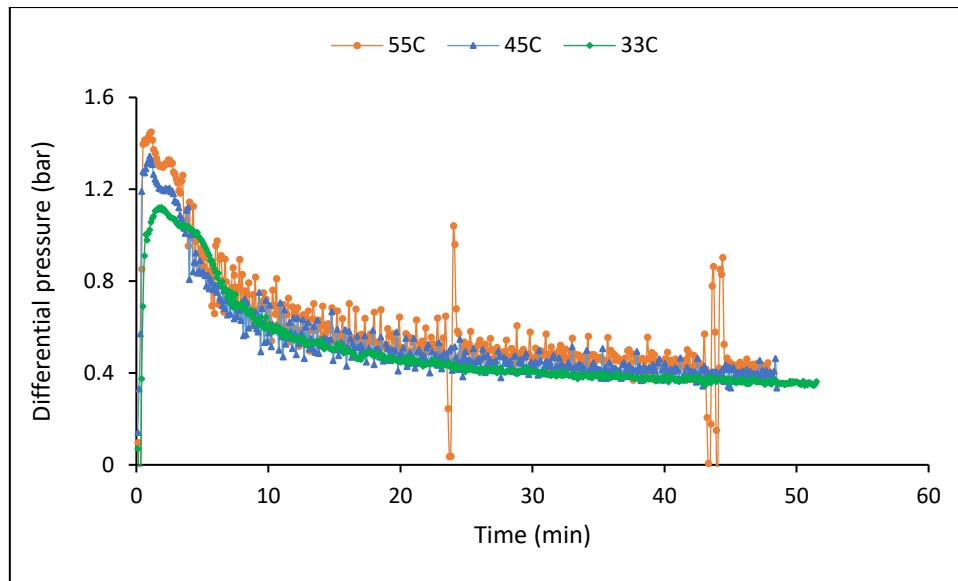


Figure 9: Effect of temperature on the differential pressure profile of ScCO₂-water displacements conducted at 75 bar and 0.4 ml/min.

3.1.4 Effect of Injection Rate on the Differential Pressure Profile of ScCO₂-Water Drainage Displacements.

To investigate the effect of CO₂ injection rate on the differential pressure profile and water recovery of ScCO₂-water displacements, three series of experiments were performed under various fluid pressures (74-90 bar), temperatures (33 and 45 °C) and injection rates (0.1, 0.4, and 1ml/min).

Figure 10-12 present the effect of increasing CO₂ injection rate on the differential pressure profile at different conditions. The data show that increasing injection rate caused a considerable increase in the maximum and quasi-differential pressures, the extent of this increase increased with the temperature and reduced with the fluid pressure. The decrease or increase in the corresponding time with increasing injection rate is dependent on the fluid pressure and temperature; the corresponding time decreased at low-temperature (33 °C) and high-fluid pressure (90 bar) conditions but increased at high-temperature (45 °C) and high-fluid pressure (90 bar) conditions. The data show that as the injection rate increased from 0.4 to 1 ml/min: (I) the maximum-differential pressure increased by 56% (from 0.599 to 0.935 bar), the quasi-differential pressure was constant, and the corresponding time reduced by 33.33% (from 0.6 to 0.4 min) for the displacements conducted at 90 bar and 33 °C, as shown in Figure 10; (II), the maximum-differential pressure increased by around 62% (from 1.035 to 1.674 bar) and the quasi-differential pressure increased by around 85.5% (from 0.234 to 0.434 bar), the

corresponding time increased by 340% (from 0.5 to 2.2 min) for the displacements conducted at 90 bar and 45 °C, as shown in [Figure 11](#); and (III) the maximum-differential pressure increased by about 111% (from 1.16 to 2.4446 bar), the quasi-differential pressure by 129% (from around 0.271 to 0.621 bar), and the corresponding time was constant for the displacements conducted at 74 bar and 45 °C, as shown in [Figure 12](#).

According to Eq.1, the increase [observed](#) in the differential pressure can be related to the increase in the viscous forces owing to increasing the injection rate; however, the extent of the increase is dependent on the associated fluid pressure and temperature conditions. The reduction in corresponding time at low-temperature and high-pressure conditions can be related to the low maximum-differential pressure because of the transformation of the ScCO₂-water displacement behaviour to the likeness of a liquid CO₂-water displacement ([Al-Zaidi et al., 2018b](#)); while the increase in the corresponding time at high-temperature and high-pressure conditions can be associated with the high maximum-differential pressure because of the transformation of the ScCO₂-water displacement profile to the likeness of a gaseous CO₂-water displacement ([Al-Zaidi et al., 2018b](#)).

The data in [Figure 11](#) also show that the increase in the injection rate caused a slight change in the differential pressure profile. After its first reduction, the differential pressure increased for a small period, then continued its reduction until the end of the displacements; the rate of the reduction decreased with time. The increase in the differential pressure profile for a small period means that the injected CO₂ had to open new flow paths after the initial entry. This depends on the core sample properties [and operational conditions due to their direct impact on](#) capillary and viscous forces. Moreover, the data from [Figure 11](#) also show that the differential pressure profile of the 0.4 and 0.6 ml/min experiments became nearly identical, during the last period, after around 14 min. This suggests that the effect of pressure drop due to viscous forces became negligible after around 14 min [as the majority of water was depleted](#).

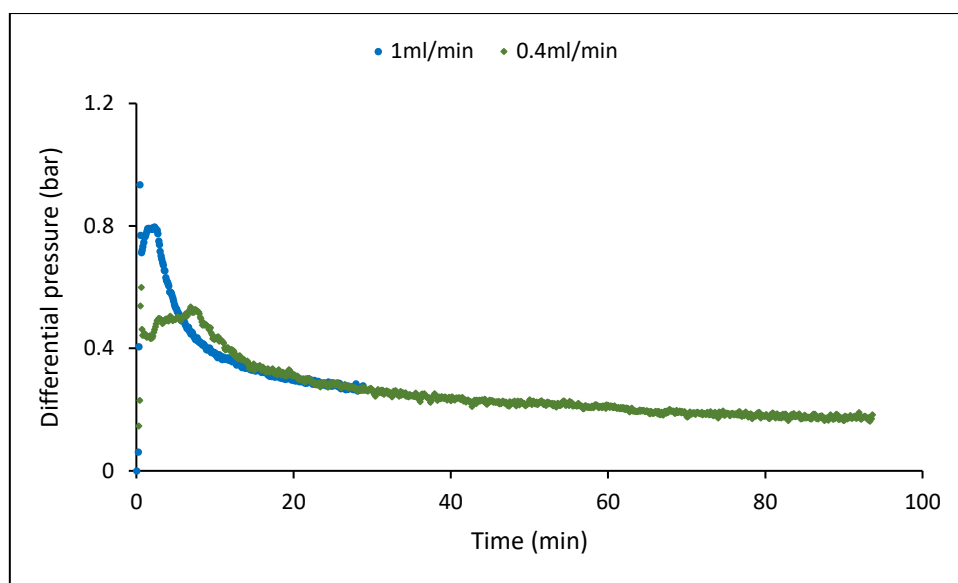


Figure 10: Effect of CO₂ injection rate on the differential pressure profile of ScCO₂-water displacements conducted at 90 bar and 33 °C.

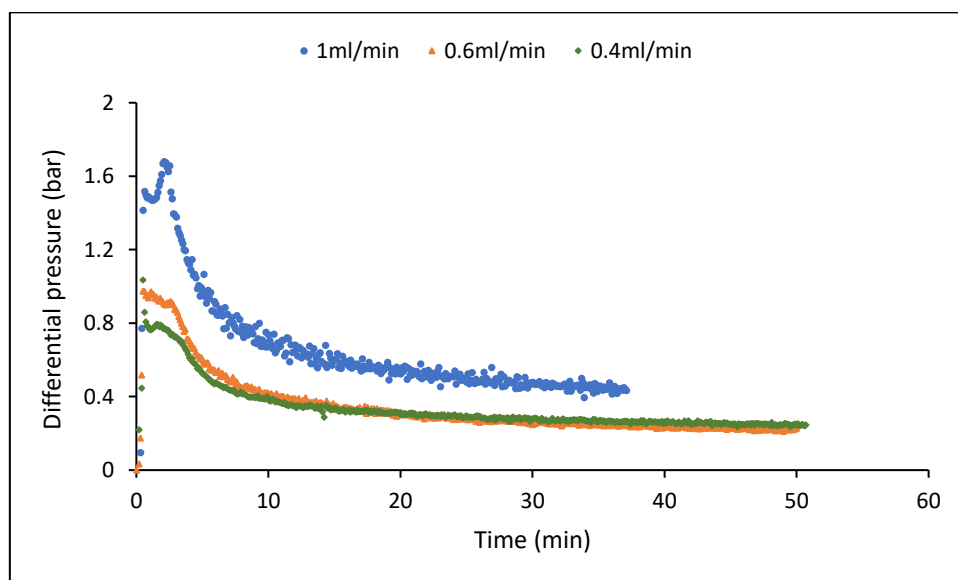


Figure 11: Effect of CO₂ injection rate on the differential pressure profile of ScCO₂-water displacements conducted at 90 bar and 45 °C.

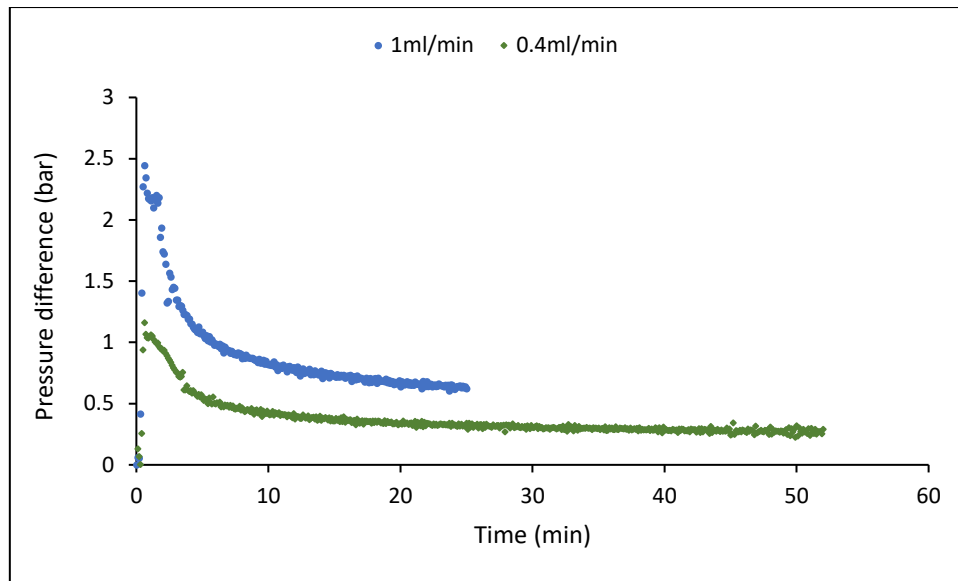


Figure 12: Effect of CO₂ injection rate on the differential pressure profile of ScCO₂-water displacements conducted at 74 bar and 45 °C.

In summary, the results show that for all fluid pressures, temperatures and CO₂ injection rates the differential pressure increased sharply; then, it dropped steeply (under low pressures and high temperature conditions) or gradually (under high pressures and low temperature conditions) until it reached an almost quasi-steady status. Increasing fluid pressure caused the differential pressure profile of the ScCO₂-water displacements to transform to the likeness of liquid CO₂ behaviour. On contrary, increasing temperature caused it to transform to the likeness of gaseous CO₂ behaviour. Increasing injection rate caused the transition from gaseous to liquid CO₂ behaviour to occur at lower fluid pressures. Increasing fluid pressure caused a slight change in the differential pressure profile; the differential pressure profile of the 90 bar-experiment increased gradually until it became slightly higher than the differential pressure profile of the 80 bar-experiment at the end of the flooding. Increasing temperature at a lower fluid pressure (75 bar) caused the appearance of the differential pressure oscillations. The increase in the injection rate caused a slight change in the differential pressure profile. After its first reduction, the differential pressure increased for a small period, then continued its reduction until the end of the displacements.

Increasing fluid pressure caused a substantial drop in the maximum and quasi-differential pressures; the extent of this drop decreased with the injection rate. On the other hand, increasing

injection rate and temperature caused a considerable increase in the maximum and quasi-differential pressures; this considerable increase is dependent on the concomitant operational conditions. For increasing temperature, the maximum and quasi-differential pressures increased with the injection rate. For increasing injection rate, the maximum and quasi-differential pressures increased with the temperature and reduced with the fluid pressure. The results indicate that capillary forces have more impact on the differential pressure profiles than viscous forces when fluid pressure and temperature increased but the viscous forces have more impact when injection rate increased significantly.

The magnitude of the corresponding time is dependent on many factors such as the operational conditions (e.g. CO₂ injection rate, fluid pressure and temperature) and the core sample and fluids properties. This is because of the direct impact of the above factors on the capillary entry pressure (due to their influence on the CO₂-water interfacial tension and core sample wettability) as well as their direct impact on the density of the injected fluid and the expansion effect. For illustration, a displacement characterized by lower entry pressure, dense CO₂ and high injection rate will reach its maximum-differential pressure faster. Increasing injection rate caused the corresponding time to decrease at low-temperature (33 °C) and high-fluid pressure (90 bar) conditions but increase at high-temperature (45 °C) and high-fluid pressure (90 bar) conditions. For increasing fluid pressure and temperature, the decrease or increase in the corresponding time is dependent on the injection rate. For increasing fluid pressure, the corresponding time increased at an injection rate of 0.1 ml/min but decreased at an injection rate of 0.4 ml/min and higher. However, for increasing temperature, the corresponding time decreased at an injection rate of 0.1 ml/min but increased at an injection rate of 0.4 ml/min and higher.

3.2 Water Production Behaviour

This section deals with the impact of fluid pressure, temperature, and CO₂ injection rate on the production behaviour of supercritical CO₂-water displacements.

3.2.1 Effect of Fluid Pressure on ScCO₂-Water Production Behaviour

Figure 13 shows the effect of increasing fluid pressure on the cumulative produced volumes. The data reveal that increase in fluid pressure led to a reduction in the cumulative produced volumes. As the fluid pressure increased, the difference between the cumulative produced volumes and the cumulative injected volumes decreased. The difference was 1.9, 0.75, 0.38, and -0.363 for the experiments performed at 75, 77, 80, and 90 bar, respectively. The 75 bar-experiment corresponded to the highest difference while the 90 bar-experiment corresponded to the lowest. For the experiments performed at 75, 77, and 80 bar, the cumulative produced volumes were higher than the cumulative injected volumes. As the fluid pressure increased to 90 bar, the cumulative produced volumes became less than the cumulative injected volumes. The high cumulative produced volumes at low pressures mean less volume of CO₂ can be stored at these conditions. However, if the goal is to enhance oil production by reducing the cost of CO₂ then low pressures is a better choice. The increase observed in the cumulative produced volumes can be related mainly to the water production. This is because after about 5 min until the end of the displacements the cumulative produced volumes and the cumulative injected volumes were identical. The similarity between the cumulative injected and produced volumes means that CO₂ volumes cannot cause an increase in the cumulative volumes under our experimental rig configuration. This is because the produced CO₂ shrinks again to its original injected volume after leaving the core sample. Thus, the increase in the cumulative volumes at early stages might reflect the displacement efficiency and the impact of CO₂ expansion.

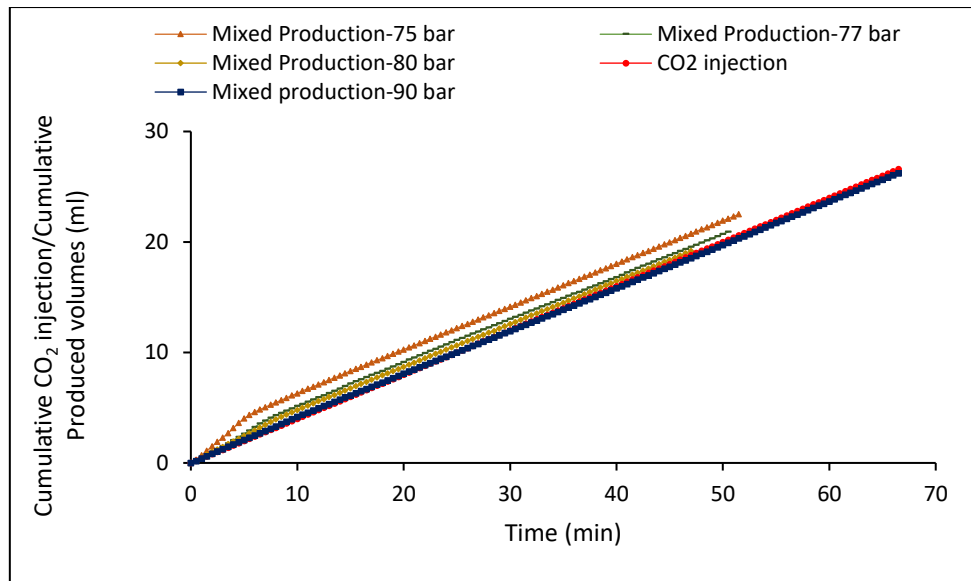


Figure 13: Effect of fluid pressure on the cumulative produced volumes of water and CO₂ of ScCO₂-water displacements conducted at 0.4 ml/min, and 33 °C.

3.2.2 Effect of Temperature on ScCO₂-Water Production Behaviour

The effect of increasing temperature on the cumulative produced volumes is shown in Figure 14.

The data reveal that as temperature increased, the cumulative produced volumes increased considerably. As the temperature increased from 33 °C to 55 °C, the cumulative produced volumes increased by around 10.6% (from 20.2 to 22.338 ml). The increase in the cumulative produced volumes can be attributed to the increasing gas expansion and the reducing CO₂ solubility because of increasing temperature (Bachu and Bennion, 2008; Yang et al., 2007). The increase in cumulative produced means less CO₂ can be stored in hot temperature environment.

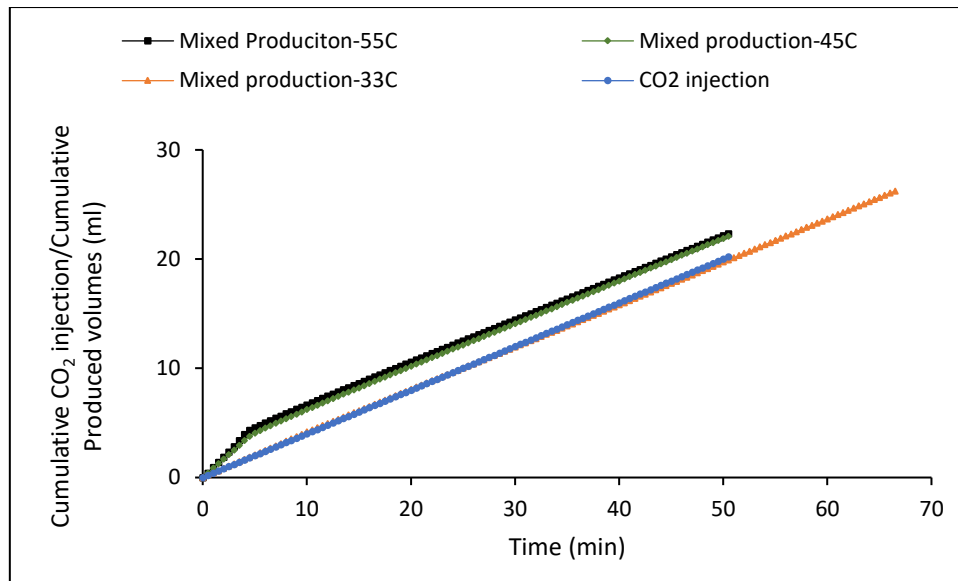


Figure 14: Effect of temperature on the cumulative produced volumes of water and CO₂ of ScCO₂-water displacements conducted at 90 bar and 0.4 ml/min.

3.2.3 Effect of Injection Rate on Water Production Behaviour during ScCO₂ injection.

Figure 15 shows the effect of increasing injection rate on the cumulative produced volumes. The data from Figure 14 and Figure 15 reveal that as the injection rate increased, from 0.1 to 0.4 ml/min, the cumulative produced volumes increased. The cumulative produced volumes increased by around 9% (from 22.627 to 24.662 ml) at 33 °C and increased by around 2.7% (from 13.711 to 14.078 ml) at 45 °C. The increase in the cumulative volume with increasing injection rate can be related to the increase in water recovery due to the increase in the viscous forces at the expense of capillary forces, which try to reduce production.

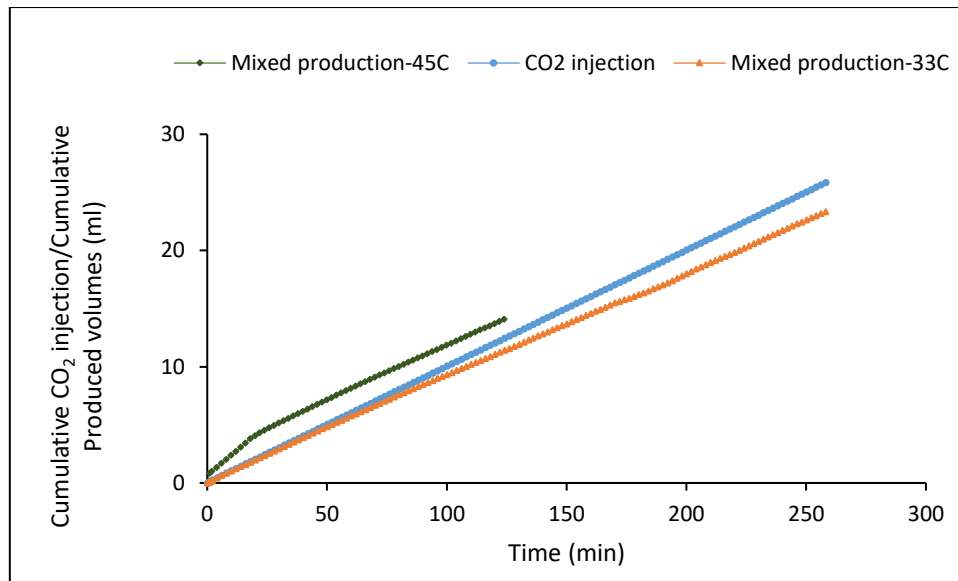


Figure 15: Effect of temperature on the cumulative produced volumes of water and CO₂ of ScCO₂-water displacements conducted at 90 bar and 0.1 ml/min.

In summary, the increase in fluid pressure led to a reduction in the cumulative produced volumes while increasing temperature and injection rate caused an increase in them.

3.3 Effect of Fluid Pressure, Temperature, and Injection Rate on Endpoint CO₂ Effective (Relative) Permeability and Residual Water Saturation

The determination of the effective and relative permeability of CO₂ is of practical interest for CO₂ sequestration processes in subsurface formations ([Rathnaweera et al., 2015](#)) such as determining the efficiency and integrity of CO₂ storage ([Busch and Müller, 2011](#)). At the end of the flooding experiment, the volume of the produced water was measured, and the residual water saturation was calculated using the mass balance concept. Then, the core sample was weighed to confirm the calculated residual water saturation. To calculate the endpoint effective permeability and endpoint relative permeability of supercritical CO₂ using Darcy's law, the average differential pressure and the average CO₂ outflow rate of the last period were used ([Akbarabadi and Piri, 2011](#); [Chang et al., 2013](#)). The CO₂ viscosity at the fluid pressure and temperature was calculated using the Peace software website ([Peace software, 2017](#)).

Table 1 presents the endpoint effective (K_{fCO_2}) and relative permeabilities (K_{rCO_2}) of supercritical CO₂ as well as the residual water saturation (S_{wr}) as a function of fluid pressure, temperature, and

injection rate. The results show that both K_{rCO_2} ([Armstrong et al., 2017](#)) and S_{wr} are dependent on the experimental conditions at which they are measured. The S_{wr} was in range of 0.34 to 0.41 while K_{rCO_2} was less than 0.37. Akbarabadi and Piri, as well as, Busch and Müller observed a low relative permeability for CO₂ ([Akbarabadi and Piri, 2011](#); [Busch and Müller, 2011](#)), too. Such low relative permeability would tend to decrease injectivity while increasing displacements efficiency ([Levine et al., 2011](#)). The results showed a remarkable impact for the parameters investigated on the K_{rCO_2} with a lesser impact on the S_{wr} . The data from [Table 1](#) show also that the amount of the injected volumes showed no impact on the S_{wr} trend. Based on the logarithmic values of the viscosity ratio (M) and capillary number (Ca), the invasion pattern of this study is capillary fingering regime, as shown in [Figure 16](#).

In general, increasing fluid pressure led to an increase in the K_{rCO_2} . This is in agreement with the findings of Bennion and Bachu ([Bennion and Bachu, 2006a](#)). The magnitude of the increase in the K_{rCO_2} with increasing fluid pressure depends on the concomitant injection rate and temperature; the endpoint decreased with increasing the injection rate and temperature. The highest increase occurred with low injection rate and low-temperature. As the fluid pressure increased from 75 to 90 bar at 33 °C, the K_{rCO_2} increased: (I) by about 0.114 for the 0.1 ml/min-displacements, (II) by around 0.08 for the 0.4 ml/min-displacements, and (III) by approximately 0.07 for the 1 ml/min-displacements. However, as the fluid pressure increased from 75 to 90 bar at 45 °C, the K_{rCO_2} increased by about 0.046 for the 0.4 ml/min-displacements. The reduction in the K_{rCO_2} as the temperature increased from 33 to 45 °C might be associated with the increase in the capillary forces which hinder the flowrate of the injected CO₂. It should be noted that Liu et al also observed an increase in the K_{rCO_2} with increasing fluid pressure ([Liu et al., 2010](#)). Bennion and Bachu observed also an increase in the K_{rCO_2} and the maximum endpoint CO₂ saturation (i.e. reduction in the S_{wr}) and attributed that to decreasing interfacial tension with increasing pressure ([Bennion and Bachu, 2006a](#)).

The results from [Table 1](#) show that in comparison to its impact on K_{rCO_2} , the fluid pressure showed a lesser influence on the S_{wr} . Overall, the increase in fluid pressure led to decrease the S_{wr} ([Bennion and Bachu, 2006a](#)). Increasing the fluid pressure from 75 to 90 bar at 33 °C resulted in decreasing the S_{wr} : (I)

by 0.027 for the 0.1 ml/min displacements, (II) by 0.015 for the 0.4 ml/min displacements, and (III) by 0.016 for the 1 ml/min displacements. Increasing the fluid pressure from 75 to 90 bar at 45 °C and 0.4 ml/min produced a reduction in the S_{wr} by 0.025. The main reasons behind the reduction in the S_{wr} are the increase in the Ca and the reduction in the M as illustrated in Table 1. It should be noted that the displacement conducted at 80 bar-0.1 ml/min-33 °C showed the lowest S_{wr} of 0.343 and the highest K_{rCO_2} of around 0.223, the reason is not entirely clear. However, this might be related to the transition from the likeness of gaseous to liquid CO₂ behaviour as the fluid pressure increased from 75 to 80 and then to 90 bar, as shown in Figure 1.

The results from Table 1 reveal that the impact of the temperature on the K_{rCO_2} depends largely on the associated fluid pressure and injection rate. The K_{rCO_2} showed a declining trend with increasing temperature at high-fluid pressures (90 bar) but an increasing trend at lower-fluid pressures (75 bar). With increasing fluid temperature, the percentage of the reduction in the K_{rCO_2} at high-fluid pressures increased with the injection rate. For the 90 bar-core floodings, increasing temperature from 33 to 45 °C at low injection rate (0.1ml/min) caused the K_{rCO_2} to decrease by around 0.081. As the temperature increased from 33 to 55 °C, the K_{rCO_2} dropped by about 0.121 for the 0.4ml/min-displacements, and by 0.239 for the 1 ml/min-displacements. On the other hand, for the 75 bar-core floodings, as the temperature increased from 33 to 55 °C, the K_{rCO_2} increased slightly by around 0.015; the reason is not clear. However, it might be also associated with the slight increase in pressure drop despite the high reduction in CO₂ viscosity with increasing temperature; the slight increase in pressure drop might be associated with the transfer of supercritical CO₂ behaviour towards gaseous CO₂ behaviour, especially under high-temperature and low-fluid pressure conditions, as shown in Figure 9. It should be noted that there is no consensus in the literature about the effect of temperature on the relative permeability. For illustration, Bennion and Bachu (Bennion and Bachu, 2006b) observed a reduction in the relative permeability with increasing temperature. On the other hand, Lee et al. observed almost no change in the relative permeability with increasing temperature (Lee et al., 2009).

Generally, the results from [Table 1](#) reveal that the increase in temperature led to an increase in the S_{wr} . The magnitude of the increase depends on the associated fluid pressure and injection rate. Overall, as the temperature increased, the increase in the S_{wr} increased with the injection rate and fluid pressure. As the temperature increased from 33 to 45 °C, the S_{wr} increased by 0.004 for the experiments conducted at 90 bar and 0.1 ml/min. When the temperature increased from 33 to 55 °C, the S_{wr} increased by 0.021 for the experiments conducted at 90 bar and 0.4 ml/min, by 0.041 for the experiments conducted at 90 bar and 1 ml/min, and by 0.018 for the experiments conducted at 75 bar and 0.4 ml/min and. Overall, the reduction in the K_{rCO2} and the increase in S_{wr} can be related to the reduction in the Ca and the increase in the M .

In general, the results from [Table 1](#) reveal that the increase in the CO₂ injection rate caused a rise in the K_{rCO2} and a reduction in the S_{wr} . These findings agree qualitatively with those [obtained](#) by Chang et al. and Akbarabadi and Piri ([Akbarabadi and Piri, 2011](#); [Chang et al., 2013](#)). As the injection rate increased, the change in the K_{rCO2} and S_{wr} increased with the fluid pressure but decreased with the temperature. Overall, as the injection rate increased from 0.1 to 1 ml/min, the K_{rCO2} increased by about 0.038 for the 75 bar-33 °C-core floodings, by around 0.134 for the 90 bar-33 °C-core floodings, by about 1.68 for the 74 bar-45 °C-core floodings, and by 0.084 for the 90 bar-45 °C-core floodings. The S_{wr} decreased by 0.033, 0.034, 0.006, and 0.012 for the above experiments, respectively. [Since \$M\$ is constant](#), the reduction in the S_{wr} can be related mainly to the increase [observed](#) in the Ca . On the other hand, the displacements conducted at 80 bar showed an opposite behaviour. As the injection rate increased from 0.1 to 1ml/min, the K_{rCO2} decreased by 0.08 and the S_{wr} increased by 0.041. The reason is not entirely clear. However, this might be related to the transition of supercritical CO₂ behaviour from gaseous to liquid-like CO₂ behaviour as the fluid pressure increased from 75 to 80 and then to 90 bar, see [Figure 1](#).

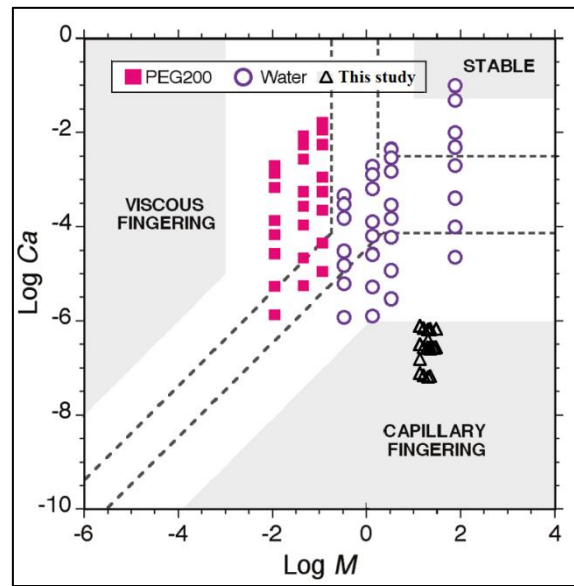
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Table 1: Effect of fluid pressure, temperature, and injection rate on the endpoint effective permeability (K_{fCO_2}), endpoint relative permeability (K_{rCO_2}) and residual water saturation (S_{wr}).

<i>Parameter</i>	<i>Experiment</i>	<i>K_{fCO₂} (mD)</i>	<i>K_{rCO₂}</i>	<i>S_{wr}</i>	<i>Ca</i>	<i>M</i>	<i>Injected CO₂ (ml)</i>
Fluid Pressure Effect	75 bar-0.1 ml/min-33°C	1.095	0.06982	0.411	6.417E-08	22.47	20.19
	80 bar-0.1ml/min-33°C	3.495	0.22287	0.343	6.613E-08	16.31	24.7
	90 bar-0.1ml/min-33°C	2.880	0.18370	0.384	7.413E-08	13.91	25.82
	75 bar-0.4ml/min-33°C	1.858	0.11849	0.372	2.566E-07	22.47	20.6
	77 bar-0.4ml/min-33°C	2.207	0.14077	0.374	2.594E-07	19.53	19.84
	80 bar-0.4ml/min-33°C	2.388	0.15228	0.372	2.645E-07	16.31	18.36
	90 bar-0.4ml/min-33°C	3.128	0.19949	0.357	2.965E-07	13.91	37.36
	75 bar-1ml/min-33°C	1.696	0.10818	0.366	6.417E-07	22.47	20
	80 bar-1ml/min-33°C	2.307	0.14715	0.362	6.613E-07	16.31	20.5
	90 bar-1ml/min-33°C	2.815	0.17951	0.35	7.413E-07	13.91	20.3
	75 bar-0.4ml/min-45°C	1.897	0.12099	0.39	2.577E-07	29.59	19.52
	80 bar-0.4ml/min-45°C	2.714	0.17306	0.363	2.497E-07	27.93	19.24
	90 bar-0.4ml/min-45°C	2.619	0.16701	0.365	2.467E-07	20.62	20.04
	90 bar-0.1ml/min-33°C	3.677	0.23451	0.384	7.413E-08	13.91	25.82
	90 bar-0.1ml/min-45°C	2.404	0.15330	0.388	6.168E-08	20.62	25.14
	90 bar-0.4ml/min-33°C	4.019	25.632	0.357	2.965E-07	13.91	37.36
	90 bar-0.4ml/min-45°C	2.629	0.16769	0.365	2.467E-07	20.62	20
	90 bar-0.4ml/min-55°C	2.123	0.13538	0.378	2.445E-07	22.73	20.08
Temperature Effect	90 bar-1ml/min-33°C	5.780	0.36862	0.35	7.413E-07	13.91	20.3
	90 bar-1ml/min-45°C	2.918	0.18607	0.374	6.168E-07	20.62	36.7
	90 bar-1ml/min-55°C	2.032	0.12.960	0.391	6.114E-07	22.73	18.8
	75 bar-0.4ml/min-33°C	1.921	0.12254	0.372	2.566E-07	22.47	20.6
	75 bar-0.4ml/min-45°C	1.995	0.12722	0.39	2.577E-07	29.59	19.4
	75 bar-0.4ml/min-55°C	2.160	0.13777	0.39	2.641E-07	25.91	19.16
	75 bar-0.1ml/min-33°C	1.095	0.06982	0.411	6.417E-08	22.47	20.19
	75 bar-0.4ml/min-33°C	1.921	0.12254	0.372	2.566E-07	22.47	20.6
	75 bar-1ml/min-33°C	1.696	0.10818	0.378	6.417E-07	22.47	20
	90 bar-0.1ml/min-33°C	3.677	0.23451	0.384	7.41E-08	13.91	25.82
Injection Rate Effect							

90 bar-0.2ml/min-33°C	1.755	0.1119	0.386	1.48E-07	13.91	17.24
90 bar-0.4ml/min-33°C	4.019	0.25632	0.357	2.97E-07	13.91	37.36
90 bar-1ml/min-33°C	5.78	0.36862	0.35	7.41E-07	13.91	20.3
74 bar-0.4ml/min-45°C	2.902	0.18508	0.39	2.60E-07	29.94	25
74 bar-1ml/min-45°C	3.166	0.20192	0.384	6.50E-07	29.94	20.56
90 bar-0.1ml/min-45°C	2.404	0.1533	0.368	6.17E-08	20.62	25.14
90 bar-0.4ml/min-45°C	2.629	0.16769	0.365	2.47E-07	20.62	19.76
90 bar-0.6ml/min-45°C	4.333	0.27636	0.353	3.70E-07	20.62	29.63
90 bar-1ml/min-45°C	3.711	0.23666	0.356	6.17E-07	20.62	37.1
80 bar-0.1ml/min-33°C	3.569	0.22761	0.343	6.613E-08	16.31	24.7
80 bar-0.4ml/min-33°C	2.388	0.15228	0.372	2.645E-07	16.31	18.36
80 bar-1ml/min-33°C	2.307	0.14715	0.384	6.613E-07	16.31	20.5

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618

619 Figure 16: Stability diagram showing three flow regimes and the locations of the PEG200, water displacement, and
620 the data of this study. The dashed lines indicate the flow regimes according to Zhang et al., and the shaded areas
621 indicate flow regimes according to Lenormand et al. (Lenormand et al., 1988; Zhang et al., 2011).

622 4 Conclusion

623 This study investigated the impact of fluid pressure, temperature, and CO₂ injection rate on the
624 dynamic pressure evolution, displacement efficiency, and endpoint CO₂ effective (relative)
625 permeability during the injection of supercritical CO₂ into a water-saturated sandstone core sample.
626 The experiments highlight the importance of the balance between capillary and viscous forces on the

pressure and production data. The results reveal that the extent of the impact of each parameter (e.g. fluid pressure) on the pressure and production profiles is a function of the associated parameters (e.g. temperature and injection rate). The results indicate that capillary forces dominate the multiphase flow characteristics as fluid pressure and temperature are increased.

Importantly, the results demonstrate that increasing fluid pressure caused a considerable reduction in the differential pressure and a transformation of the profile of the ScCO₂-water displacements to be similar to that of liquid CO₂-water displacements; while, increasing temperature resulted in a significant increase in the differential pressure profile and a transition towards that of gaseous CO₂-water displacements. Increasing the injection rate caused the transformation to occur at lower pressures, and led to a substantial increase in the differential pressure; the extent of this increase increased with increasing temperature and reduced with increasing fluid pressure. The changes observed in the differential pressure with varying fluid pressure and temperature reflect a change in the influence of the capillary forces. The change in the capillary forces will have a direct impact on the displacement efficiency and the entry pressure. For illustration, the reduction in the capillary forces with increasing fluid pressure will reduce the entry pressure; thereby, it will have a reduction impact on the storage capacity and sealing efficiency of the target formation by enhancing the upward migration of CO₂. The reduction observed in the differential pressure as CO₂ transformed to a liquid-like behaviour means less energy is required for the displacement of fluids in host formations, which can reduce the cost of production significantly.

Also, of particular importance is that increasing temperature at a lower fluid pressure (75 bar) caused the appearance of the differential pressure oscillations. The appearance of the oscillations can increase CO₂ residual saturation due to the re-imbibition process accompanied with these oscillations, thereby increasing the storage capacity and integrity of CO₂. The differential pressure required to open the

blocked flow channels during these oscillations can be useful in calculating the largest effective pore diameters and hence the sealing efficiency of the rock.

The time required to reach the maximum differential pressure, i.e. the corresponding time, is dependent on fluid pressure, temperature, and injection rate. The change in the corresponding time might give an indication whether the change in the operational conditions can hasten or delay the time of CO₂ breakthrough out of the system.

The increase in fluid pressure led to a reduction in the cumulative produced volumes. On the other hand, increasing temperature and injection rate caused an increase in the cumulative produced volumes.

The results show that both endpoint relative CO₂ permeability (K_{rCO_2}) and residual water saturation (S_{wr}) are dependent on the experimental conditions at which they are measured. The S_{wr} was in range of 0.34 -0.41 while K_{rCO_2} was less than 0.37. Increasing pressure and injection rate caused an increase in K_{rCO_2} and a reduction in S_{wr} . K_{rCO_2} showed a declining trend with increasing temperature at high fluid pressures (90 bar) but an increasing trend at lower fluid pressures (75 bar). S_{wr} increased as temperature increased.

Acknowledgements: The authors wish to thank the Higher Committee for Education Development in Iraq and the Ministry of Oil in Iraq for their sponsorship of the first author PhD study.

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